Stakeholder Comments Template

Review TAC Structure Straw Proposal

This template has been created for submission of stakeholder comments on the Review Transmission Access Charge (TAC) Structure Straw Proposal that was published on January 11, 2018. The Straw Proposal, Stakeholder Meeting presentation, and other information related to this initiative may be found on the initiative webpage at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ReviewTransmissionAccessChargeStructure.aspx

Upon completion of this template, please submit it to initiativecomments@caiso.com.

Submitted by	Organization	Date Submitted
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Submissions are requested by close of business on **February 15, 2018.**

Please provide your organization's comments on the following issues and question.

CLECA appreciates the effort by the CAISO staff to improve its understanding of the TAC ratemaking and transmission planning process (TPP). CLECA had expressed concerns about incorrect information in prior drafts and incorrect information supplied by some parties due to their lack of understanding the complex details of transmission cost recover and ratemaking. Most of these issues have been resolved in the current straw proposal, which is a significant improvement over prior drafts. However, additional refinement is needed.

The straw proposal focuses primarily on cost causation, which is important and challenging in the context of a transmission system which has evolved in differing ways. As we have noted before, the creation of the CAISO grid and the introduction of open access transmission service has led to cost drivers that were different from those present when the utilities were vertically integrated and the grid was used to bring utility-owned generation from sometimes remote locations to load centers. As recognized in the straw proposal, more recent grid investments have included those for bringing in vastly increasing amounts of renewable generation, reduction of congestion, and reliability; repair and replacement have also been increasing. We agree with the points made at the Market Surveillance Committee (MSC) meeting that further study of the drivers of future transmission investment is needed. A discussion with participating transmission owners (PTOs) to develop a data base of recent and proposed transmission system investments would be very useful in determining future cost drivers. At the same time, we understand that not all projected investments are made; projects are cancelled, and needs shift, as has been demonstrated in the TPP. There is no perfect way to determine cost drivers or to allocate costs.

While there has been considerable attention paid to costs, the issue of the various benefits to customers that result from being connected to the power grid is inadequately discussed in the straw proposal. A customer with its own generation system, either behind the meter or contracted to generation located on the same distribution circuit, receives significant reliability benefits from a grid connection. The utility is still expected to serve the customer's power requirements, should the customer's system fail or be down for maintenance. In addition, it is incorrect to conclude such customers do not use the transmission system. It is not a simple accounting exercise to conclude that 10 MW of distributed generation contracted to serve 10 MW of load on the distribution system *a prioi* does not use the transmission system. On a regular basis, the customer's power requirements may not exactly match the power output from its contracted distributed energy resource; thus, the customer must rely upon the utility system to make up the difference.[1] Any injection, or withdrawal, of power will affect flows on nearby T&D lines as that is the nature of AC electrical system. While simple accounting concludes the power never left the distribution system, the reality is some of the power will flow elsewhere. This is analogous to loop-flow problems that occur in the bulk power system. The accounting schedule across a pathway does not match the reality of the actual power flow. In addition, when the output of a distributed generator changes—or should the distributed generation resource trip off-line—the units providing regulation service on the transmission system will instantly react. Thus, it is incorrect to conclude distributed generation either behind or in front of the meter does not use the transmission grid. FERC guidance in Order 1000 on cost allocation states that those receiving benefits should be assigned costs.

Finally, we note that during the formation of the CAISO, Enron attempted to make similar arguments that distributed generation does not use the transmission grid. FERC has rejected the argument of a "distribution only service" that does not use the transmission system:

> *Enron failed to demonstrate that wholesale-only distribution service could realistically be provided, from a technical standpoint. Enron has failed to answer the ISO's concern about avoidance of costs properly charged for services the ISO would provide, even if contractually the ISO services were not requested. Provision of wholesale distribution-only service would unjustly permit a customer, such as Enron, to avoid its share of the costs associated with the construction, maintenance, and operation of the ISO Grid. The ISO-controlled grid is the very backbone of the service that Enron now proposes to implement under the Companies' [Wholesale Distribution Tariffs] WDTs. The theory behind Enron's distribution-only service depends on the technical ability of such service to operate in isolation from the ISO grid. If anything has been proven in respect to this issue, it is that*

[1] It may be possible that a customer with behind the meter generation and storage (depending on the sophistication of its power management system) would not at certain times rely on utility service to provide regulation between its electrical need and generation output.

distribution-only service would have numerous effects on the ISO grid, and cannot be performed in isolation from the ISO grid.[2]

EIM Classification

1. Please indicate if your organization supports or opposes the ISO's initial EIM classification for the Review TAC Structure initiative. Please note, this aspect of the initiative is described in Section 4 of the Straw Proposal. If your organization opposes the ISO initial classification, please explain your position.

CLECA supports the classification for the CAISO Governing Board having primary review as the Energy Imbalance Market (EIM) transfers are exempt from the Transmission Access Charge (TAC) or Wheeling Access Charge (WAC).

Ratemaking Approaches

2. Please provide your organization's feedback on the three ratemaking approaches the ISO presented for discussion in Section 7.1 of the Straw Proposal. Does your organization support or oppose the ISO relying on any one specific approach, or any or all of these ratemaking approaches for the future development of the ISO's proposals? Please explain your position.

From the Straw Proposal, the three ratemaking approaches the ISO presents for this discussion are:

1. Charge TAC according to cost causation and cost drivers when decisions to invest in transmission infrastructure were made. *i.e.*, load for whom the facilities were built should continue to pay for transmission built to serve them, regardless if their usage patterns have changed.
2. Charge TAC according to current usage (and benefits), which may be different than the previous usage. If the ISO took this approach, then it needs to decide how to best characterize and measure current usage and benefits.
3. Charge TAC to send price signals as incentives to modify future behavior. This principle can potentially reduce future cost drivers and incent behavior that will support public policy goals or mandates. This approach is complicated by the multifaceted ratemaking layers regarding transmission cost recovery currently present in California.

While described as approaches, the three items are actually goals to consider when developing TAC rates. The primary purpose of the TAC is to recover the utilities' transmission revenue requirement, which can limit the ability to effectively perform the third goal. Some policy goals cannot be efficiently obtained through wholesale price signals. Certain parties want to use the TAC to provide price signals on whether generation should connect at the

[2] FERC Initial Decision in 88 FERC ¶63,007 (ER97-2358), issued September 1, 1999, page 70.

transmission or distribution system. The TAC needs to recover embedded fixed costs, but per economic principles decisions about future behavior should be made on a marginal cost basis. However, the TAC cannot be based only on marginal cost and still recover the revenue requirement. As discussed in stakeholder meetings and the CAISO Market Surveillance Committee, the best venue for marginal cost decisions is in the load serving entity (LSE) planning or contract evaluation process that can actually evaluate a generation contract with its marginal integration and delivery costs.

With regard to the issue of multifaceted ratemaking layers for transmission cost recovery, end-use customers pay for transmission through charges that are set in FERC proceedings of the PTOs and not through the TAC. As a result, the CAISO is not in a position to send price signals to end use customers and the TAC is not able to send price signals to load serving entities (LSEs),[3] who do not pay them.

Hybrid Approach for Measurement of Usage Proposal

3. Does your organization support the concept and principles supporting the development of a two-part hybrid approach for measurement of customer usage, including part volumetric and part peak-demand measurements, which has been proposed by the ISO as a potential TAC billing determinant modification under the current Straw Proposal? Please provide any additional feedback on the ISO's proposed modification to the TAC structure to utilize a two-part hybrid approach for measurement of customer usage. If your organization has additional suggestions or recommendations on this aspect of the Straw Proposal, please explain your position.

The principle of a hybrid approach is sound. A combination of peak and usage charges is used to recover costs at the retail level for non-residential customers in California. At this point, CLECA does not take a position on the merits of the 48%/52% split, or perhaps other mechanisms to split the costs. It will not be possible to be precise; however, setting a direction away from purely volumetric recovery is important and the correct approach. It may be necessary to have a phase-in to reduce possible billing impacts, should the cost allocations among PTOs change significantly. Again, it is imperative to acknowledge that these costs are collected from end-use customers, regardless of their LSE, so the customers would see these changes in their retail bills. A phase-in is frequently used in retail ratemaking to mitigate bill impacts resulting from dramatic changes in allocation among customers. A phase-in was also used to establish the current postage stamp TAC rate.

Split of HV-TRR under Proposed Hybrid Approach for Measurement of Usage

[3] TAC charges are assigned to load-serving PTOs, and not load serving entities which do not provide transmission and distribution services.

4. The ISO proposed two initial concepts for splitting the HV-TRR under two-part hybrid approach for measurement of customer use for stakeholder consideration in Section 7.2.1.2 of the Straw Proposal. Please provide your organization's feedback on these initial concepts for determining how to split the HV-TRR to allocate the embedded system costs through a proposed two-part hybrid billing determinant. Please explain your suggestions and recommendations.

   a. Please provide any additional feedback or suggestions on potential alternative solutions to splitting the HV-TRR costs for a two-part hybrid approach.

      The approach CAISO used to classify reliability projects as capacity and other projects as energy appears reasonable. However, the years selected can create significant changes to the results. For example, the CAISO noted the planning process was changed in 2010, so if data prior to 2010 was removed, then reliability projects would result in allocating 86% of the cost to peak capacity. Since transmission investments tend to be lumpy over time, this means that the allocator could change significantly. This could result in volatile cost allocation impacts to a PTO, and therefore rate impacts for its customers. This could be tempered by including forecasted projects, although they can be uncertain. Alternatively, a simple 50-50 split could be used as the goal of a phase-in and it could be reviewed over time to see if it continues to be reasonable.

   Please indicate if your organization believes additional cost data or other relevant data could be useful in developing the approach and ultimate determination utilized for splitting the HV-TRR under the proposed two-part hybrid approach. Please explain what data your organization believes would be useful to consider and why.

      Please see the response to 4a.

5. The ISO seeks feedback from stakeholders regarding if a combination of coincident and non-coincident peak demand charge approaches should potentially be used as part of the two-part hybrid approach proposed in Section 7.2.1.2. Does your organization believe it would be appropriate to utilize some combination of coincident and non-coincident peak demand methods to help mitigate the potential disadvantages of only use of coincident peak demand charges? Please provide any feedback your organization may have on the potential use of coincident versus non-coincident peak demand measurements, or some combination of both under the proposed two-part hybrid measurement of usage approach.

   CLECA is still considering whether there should be one or both such charges.

a. What related issues and data should the ISO consider exploring and providing in future proposal iterations related to the potential utilization of part coincident peak demand charge and part non-coincident peak demand charge? Please explain your position.

Coincident peak is useful to recover costs that are peak-related, such as contribution to transformer capacity. While FERC has approved the use of the twelve-monthly coincident peak (12 CP) allocation method, FERC does allow use of other methods as well (e.g., 4 or 5 CP). Alternatives to 12 CP could be considered if the level of the peak power flows measured in the individual months diverges substantially, demonstrating that the requirements on the transmission system are impacted more heavily by some months than other months.

Consideration could be given to alternative methods to ensure all customers appropriately contribute to the recovery of peak-related reliability costs, perhaps through use of a non-coincident demand charge or by a charge collected on the basis of some number of top hours. However, how to determine the cost basis for the non-coincident charge is not clear. One option would be to take a portion of the revenue requirement associated with reliability benefits and recover it from a non-coincident peak charge.

Treatment of Non-PTO Municipal and Metered Sub Systems (MSS) Measurement of Usage

6. Under Section 7.2.1.2 of the Straw Proposal the ISO indicated there may be a need to revisit the approach for measuring the use of the system by Non-PTO Municipal and Metered Sub Systems (MSS) to align the TAC billing determinant approaches for these entities with the other TAC structure modifications under any hybrid billing determinant measurement approach. Because the Straw Proposal includes modifications for utilization of a two-part hybrid measurement approach for measurement of customer usage the ISO believes that it may also be logical and necessary to modify the measurement used to recover transmission costs from Non-PTO Municipal and Metered Sub Systems (MSS) entities. The ISO has not made a specific proposal for modifications to this aspect of the TAC structure for these entities in the Straw Proposal, however, the ISO seeks feedback from stakeholders on this issue. Please indicate if your organization believes the ISO should pursue modification to the treatment of the measurement of usage approach for Non-PTO Municipal and Metered Sub Systems to align treatment with the proposed hybrid approach in the development of future proposals. Please explain your position.

Since Non-PTOs’ and MSSs’ usage (MWh) and peak load (MW) impact the CAISO transmission system in a similar manner as PTOs, it makes sense to treat them similarly and, if adopted, also use the hybrid approach.

Point of Measurement Proposal

7. Does your organization support the concepts and supporting justification for the ISO's current proposal to maintain the current point of measurement for TAC billing at end use customer meters as described in Section 7.2.3.2 of the Straw Proposal? Please explain your position.

   Yes, CLECA supports the continued measurement at the end use customer meter for measurement for TAC billing.

   CAISO should consider modifying the term Gross Load because it may not be the best description with increasing behind the meter generation and storage. To improve clarity, it may be useful to add additional terms to describe customer usage, i.e. at the meter or behind the meter. In addition, if there is a demand-related charge in the future, the usage associated with it would need a definition.

8. The ISO has indicated that the recovery of the embedded costs is of paramount concern when considering the potential needs and impacts related to modification of the TAC point of measurement. The ISO seeks additional feedback on the potential for different treatment for point of measurement for the existing system's embedded costs versus future transmission costs. Does your organization believe it is appropriate to consider possible modification to the point of measurement only for all future HV-TRR costs, or additionally, only for future ISO approved TPP transmission investment costs? Please provide supporting justification for any recommendations on this issue of point of measurement that may need to be further considered to be utilized for embedded versus future transmission system costs. Please be as specific as possible in your response related to the specific types of future costs that your response may refer to.

   CLECA supports retaining the current point of measurement at the end use customer meter. Changing the measurement point to recover new costs versus embedded costs implies that the use of those assets is different, which is not possible in an AC electric system. Consider two parallel lines, where one is new and other is old. The power will always flow equally across the two lines. It does not make sense that the measurement should be different for the two lines.

9. The ISO seeks additional stakeholder feedback on the proposal to maintain the status quo for the point of measurement. Please provide your organizations recommendations related to any potential interactions of the point of measurement proposal with the proposed hybrid billing determinant that should be considered for the development of future proposals. Please indicate if your organization has any feedback on this issue and provide explanations for your positions.

   CLECA supports the status quo for the point of measurement for the transmission system. As described earlier, all customers receive benefits from being connected to a transmission system, regardless of the location of generation assets. Therefore, the cost of the transmission system should be recovered from all customers. Moving to the hybrid approach moves closer to what is done for retail and should be an improvement over the current energy-only method to allocate transmission costs. The addition of a peak-related component will better reflect the cost impacts to the transmission system that are peak-related.

In terms of interactions, please see the comments to questions 5a and 10.

Additional Comments

10. Please offer any other comments your organization would like to provide on the Review TAC Structure Straw Proposal, or any other aspect of this initiative.

The hybrid approach may not take into account the increasing number of customers that have behind the meter generation and storage. In this case, these customers' usage and peak demand will only appear when their on-site system(s) are down for maintenance or failure, or if it is financially advantageous to exchange power with the grid from their storage systems. These customers effectively appear as standby customers, but still receive benefits from being connected to the electric grid. These benefits include reliability and access to purchase from or sell to the grid.

When the impacts of these standby customers are aggregated up to the PTO level, it can have implications for cost allocation and resulting rates. When gross load (MWh) or gross demand[4] (MW) declines, then the TAC rate components will increase. To the extent these standby customers are concentrated in a PTO, then it could have cost allocation shifting impacts through the TAC Balancing Account Adjustment (TACBAA). An extreme example is a PTO created entirely with customers with behind the meter generation and storage. In this case, the billing determinants (MWh and peak MW) would be very small, which would result in a very high average TAC rate to recover the transmission revenue requirement. Through the TACBAA, the PTO would receive a subsidy from other PTOs. In turn, this would be a credit to the transmission rates applied to its retail customers. Thus, the PTO and its customers would pay very little for transmission access, yet they would receive the reliability and financial opportunities to sell power to the transmission grid.

The concept of a standby-type charge could be used to appropriately assign costs to a PTO with a large proportion of these standby customers to appropriately set their rate commensurate with the benefits they receive. Additional work is needed to determine if the standby charge should be based upon a coincident or non-coincident peak, or possibly other possible billing determinants, and how it would be set.

[4] We use the 'gross' term to represent the end use customer demand measured at the meter consistent with the current CAISO definition of gross load.